BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2015 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast (U 39 E)	Application 14-05-024 (Filed May 30, 2014)

RESPONSE OF MARIN CLEAN ENERGY AND CITY OF LANCASTER TO OPTIONAL HOMEWORK ASSIGNMENT IN PREPARATION FOR THE MARCH 8 WORKSHOP ON PCIA REFORM

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ON BEHALF OF
MARIN CLEAN ENERGY
AND CITY OF LANCASTER

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SUMMARY OF RECOMMENDATIONS

1. The Commission should issue a single source document detailing the full PCIA calculation process from start to finish and present that document to interested parties prior to the convening of the March 8 workshop.

2. The Commission should consider PCIA reform in light of: (1) the increase in CCA load and potential CCA load; (2) further applicability of PCIA to other loads, such as green tariff shared renewables, customer generation departing load, and potentially net energy metering; (3) increased maturity in the renewable energy market; and (4) an increased statewide emphasis on solutions to climate change.

3. The Commission should require greater transparency of the PCIA inputs by making contract information public upon signature, including information such as pricing, volumes and terms of each IOUs contract contributing to the PCIA.

   - Alternatively, this contract information should be public no later than one year of signature.
   - Alternatively, the Commission should adapt confidentiality rules to: (1) review IOU determinations of public and confidential information; (2) direct IOUs to make information public when it has already been available in other public forums; and (3) determine whether the confidentiality rules are serving the public interest.
   - Alternatively, the Commission should create a category of Public Agency Participants that have a higher level of access to IOU contract information that is currently deemed confidential for Market Participants.
   - Alternatively, the Commission should direct the IOUs to provide 10-year forward forecasts of Total Portfolio Costs and percentage breakdowns of RPS and non-RPS procurement.

4. In order to ensure that non-confidential information is disclosed, the Commission should strongly and swiftly enforce rules and create consequences for failure to disclose non-confidential information that relates to the PCIA calculation. In addition, the Commission should require the IOU to reimburse impacted parties for time and resources spent preparing multiple data requests, meet and confer sessions, and motions to compel.

5. To ensure that the Total Portfolio approach to PCIA excludes avoidable costs, the Commission should: (1) require IOUs to forecast and plan around likely load departure in accordance with D.15-10-031; (2) through an annual audit, require an IOU to mitigate damages for Power Purchase Agreements; (3) through an annual audit, require an IOU to curtail generation from Utility-Owned Generation when above-market costs are avoidable.

6. The Commission must clearly define either prior to or at the March 8 workshop what the present limitations are for the stranded cost recovery of conventional, renewable, and UOG resources, because D04-12-048 is self-contradictory and vague.

7. In order to set appropriate duration limits for the PCIA, stranded cost recovery should be limited to 10 years for all resource types.

8. To limit PCIA volatility and uncertainty, the Market Price Benchmark should consider 5 years of natural gas prices instead of the current single year spot-market price.

9. The Commission should develop alternatives to the volatile year-by-year PCIA through providing a Menu of Options for repayment that departing load providers can choose from in order to prioritize their own mission and values.

10. The March 8, 2016 workshop should limit its discussion on Question 3 to clearly define what is considered "a very large [departing] load." Further considerations regarding how to treat "a very large [departing] load" should then be considered in a second workshop.

11. At a policy level, the Commission should strive for PCIA reform that is both *fair* to all forms of departing load and *flexible* enough to enable LSEs to plan around the PCIA and effectively communicate PCIA fees and rate changes to their customers.

TABLE OF CONTENTS

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I. INTRODUCTION

Marin Clean Energy ("MCE") and the city of Lancaster, operating its Community Choice Aggregation ("CCA") program through Lancaster Choice Energy ("LCE") (together with MCE, the "CCA Parties") provide the following responses to the "optional homework assignment for Power Charge indifference Adjustment (PCIA) Workshop participants" circulated to interested parties by California Public Utilities Commission ("Commission" or "CPUC") Energy Division staff on January 22, 2016. In accordance with Commission Decision ("D.") 15-12-022, the Commission plans to convene a workshop to discuss PCIA reform. This workshop is presently scheduled from 10 AM to 3 PM on March 8, 2016. The CCA Parties provide these responses to Energy Division staff and the instant proceeding's service list to recommend reforms to the PCIA to increase the transparency of the fee calculation, hold the Investor-Owned Utilities ("IOUs") accountable for minimizing stranded costs, and ensure the PCIA is more just and reasonable.

II. BACKGROUND

MCE has been closely engaged in the Pacific Gas and Electric Company's ("PG&E") Energy Resource Recovery Account ("ERRA") annual proceedings since MCE began serving its customers in May 2010. Since MCE is the first operational CCA program in California, it has led advocacy on many CCA-related regulatory matters before the Commission. MCE currently serves over 171,000 customers in Marin County, unincorporated Napa County, and the cities of Richmond, El Cerrito, San Pablo, and Benicia. MCE has already played an active role in this proceeding to ensure the proper assignment of vintages to CCA customers.

Lancaster is a thriving community of nearly 160,000 residents located approximately one hour north of Los Angeles. Attainable housing and recent economic growth have made Lancaster a very attractive choice for families and businesses that are looking to relocate, but wish to enjoy all the advantages that Southern California has to offer. Lancaster continues to aggressively pursue alternative energy solutions in hopes of bettering the current and future environmental and economic conditions of its community and region. In that context, the Lancaster City Council approved a CCA Implementation Plan for Lancaster Choice Energy in 2014, which was certified by the Energy Division on March 13, 2015. Lancaster is now the third operational CCA program in California, and the first in Southern California Edison Company's ("SCE") territory. Lancaster is interested in issues raised within the scope of PG&E's ERRA proceeding, specifically as it relates to PCIA and its reform, as the outcome will impact all CCA customers.[1]

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[1] Lancaster's motion for party status in this proceeding was granted on March 11, 2015. Lancaster has joined with MCE in filing various pleadings in this phase of the proceeding, most recently also joining with MCE and Sonoma Clean Power ("SCP") to file an opening brief and a reply brief on September 4, 2015 and September 25, 2015, respectively.

III. HOMEWORK ASSIGNMENT RESPONSES

A. QUESTION 1: Please indicate your understanding of how the PCIA is calculated, identifying, in as much detail as possible, each input to that calculation.

It is the CCA Parties' understanding that the PCIA represents the unavoidable above-market costs of the IOU electricity procurement portfolios that become stranded when load departs from that IOU's bundled electricity services to take electricity generation services from another Load-Serving Entity ("LSE"), such as an Electricity Service Provider ("ESP") or CCA. The PCIA is imposed to ensure that such departing load remains responsible for paying any procurement costs incurred on their behalf by the utility prior to their departure. The methodology for calculating the PCIA is most clearly set forth in Commission Resolution E-4475 – Exhibit A, along with the Chapter 9 of PG&E's Opening Testimony within this proceeding. Resolution E-4475 was issued by the Commission on May 10, 2012 when the PCIA methodology was last modified in order to differentiate the market price of renewable power from conventional power purchases by adopting a "Green Adder." As such, E-4475 details the calculations specific to the Market Price Benchmark ("MPB"), the Capacity Adder, and the Green Adder. In addition to these formulas, there is the calculation of the utilities Total Portfolio Indifference which determines the PCIA revenue requirement for each vintage of departing load. There is also the PCIA rate calculation which spreads the revenue requirement across the different customer classes.

While PG&E's Opening Testimony and Resolution E-4475 are the most succinct and complete references to the manner in which the PCIA is calculated, they are by no means exhaustive. For example, as part of the PCIA rate calculation component, the revenue requirement is allocated to distinct customer classes on a "Top 100 Hours" basis, where each class is allocated their share of the PCIA revenue requirement based upon their class' average top 100 hour loads overall based on recent usage data.[2] The usage of this methodology is not explicitly called out in either PG&E's Opening Testimony or Resolution E-4475. *In order to facilitate a common understanding, the CCA Parties recommend the Commission issue a single source document detailing the full PCIA calculation process from start to finish and present that document to interested parties prior to or at the March 8 workshop.*

For others' convenience, the CCA Parties include Chapter 9 of PG&E's Opening Testimony and Exhibit A from E-4475 within the Appendix to this homework response.

B. QUESTION 2: Do you believe the current PCIA methodology should be changed? If so, how and why? Please be as specific as possible.

The current PCIA methodology is flawed in numerous ways and should be modified to remedy these flaws. The existing methodology is executed in a highly non-transparent manner in which the IOUs have no incentive to minimize the "stranded costs" that feed into the PCIA calculation. This results in an extremely volatile, annually adjusted rate with no clear duration limit. The current PCIA methodology results in an unjust and unreasonable rate for CCA ratepayers that purchase electricity from cleaner sources than the IOUs' bundled electricity portfolio mix. Not only does the existing methodology result in an unreasonable rate that violates the core mission of the Commission to ensure reasonable rates, but also the PCIA obstructs the abilities of California's ratepayers to accelerate the State towards meeting its Climate Change goals initially set forth in Assembly Bill ("AB") 32 (2006) and recently expanded in Senate Bill ("SB") 350 (2015).

The Commission should take reasonable steps to change the PCIA methodology so that it is calculated in a transparent manner, with clear accountability for the IOUs to minimize the

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2 *See* D.00-06-034 for a detailed explanation of the "Top 100 Hours" methodology.

costs that go into it, so that the resulting rate is both just and reasonable for CCA ratepayers. These steps begin with revisiting the policies that inform the PCIA calculation so that they can be revised to more fairly account for CCA programs, the maturity of the renewable electricity market, the increasing diversity of forms of departing load, and the State's ambitious Climate Change goals.

The CCA Parties appreciate the Commission's continuing willingness to consider changes to and clarifications of the PCIA methodology.[3] Changes and clarifications are being considered in the context of the PCIA vintaging issue.[4] Additional changes to and clarifications of the PCIA are warranted, as further described below.

In the time since when the Commission last revised the PCIA methodology (May 2012) numerous factual circumstances have arisen that prior Commission policy has not considered:

1) Increase in CCA Load and Potential CCA Load. Load departures due to CCAs have expanded from one instance in PG&E's service territory to a statewide movement. As such, D.15-10-031 now directs both PG&E and SCE to forecast for CCA departing load as part of their biannual Bundled Procurement Planning ("BPP") process.[5]

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3 *See, e.g.,* D.08-09-012 at 57-58 ("Given the potential long-term nature of the charge, we must allow for the possibility that certain future circumstances may result in a need to modify the NBC related processes adopted in this decision."). *See also* D.13-08-023 at 17 ("The Commission remains committed to ensuring that Community Choice Aggregators and other non-utility [load-serving entities] may compete on a fair and equal basis with regulated utilities. Towards this end, we will continue to consider both the mechanics and overall fairness of cost allocation and departing load charge methodologies proposed in the future, with the specific goal of avoiding cross-subsidization.").

4 *See Assigned Commissioner's Ruling Amending Scope and Setting Out Briefing Schedule*, dated August 10, 2015, at 3 ("When the Commission issued its line of decisions and resolution on [Community Choice Aggregators] and vintaging issues, the implementation of CCA programs was in its nascent stage.").

5 See D.15-10-031 at Ordering Paragraph 1(e) and 1(o).

2) Further Applicability of PCIA to Other Loads. Additional forms of departing load are now subjected to the PCIA. For example:

a) Green Tariff Shared Renewables: In 2013, SB 43 authorized the IOUs to begin offering optional premium electricity products informally known as "Green Tariffs." D.15-01-051 determined that participants in these programs will pay the PCIA.[6]

b) Customer Generation Departing Load: In 2015 the 3,000 MW cap for Customer Generation Departing Load ("CGDL")[7] was exceeded, thereby terminating prior exemption for this type departing load from non-bypassable charges including the PCIA.[8]

c) Potential Applicability to Net Energy Metering: The Commission recently approved D.16-01-044 on the Net Energy Metering ("NEM") successor tariff. Although the decision did not go so far as to apply the PCIA to the self-generation of bundled NEM customers, there is the very real possibility that this departing load segment's exemption from the PCIA may expire too.

3) Increased Maturity in the Renewable Energy Market. The renewable electricity market has reached a state of maturity prompting the Commission to revise its policies to reduce the subsidies provided to the renewable electricity industry. This is evident in D.16-01-044 and D.15-07-001.[9]

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6 *See* D.15-01-051 at Conclusion of Law 100.

7 *See* D.03-04-030

8 *See* PG&E Advice Letter 4743-E at Attachment 1.

9 D.16-01-044 revised and reduced the incentives for ratepayer participation in NEM. D.15-07-001 significantly revised residential rates including reform of the Time of Use ("TOU") rate structures which are fundamental to the economic viability of NEM.

4) Increased Emphasis on Solutions to Climate Change. Through the recent passage of SB 350 (2015), the State of California has expanded its commitment to reducing greenhouse gas emissions and adopting renewable electricity as remedies for combating Climate Change.

All four of these significant factors must be closely considered by the Commission when revising the policies that inform the PCIA methodology. By considering these robust changes to the competitive electricity providers market, the renewable electricity market, and State electricity policy, the CCA Parties provide the following proposals to improve and refine the PCIA methodology.

1. REQUIRE GREATER TRANSPARENCY OF PCIA INPUTS

Under the guise of compliance with Commission policies on confidential information, the IOUs extensively – and excessively – redact the information used to determine the annual PCIA rate. However, much of this same information is being presented in other public forums, such as through the California Energy Commission ("CEC") Integrated Energy Policy Report ("IEPR") and through the Federal Energy Regulatory Commission ("FERC") Form 1 filings.[10] Instead of disclosing this information, the IOUs remain insistent that information such as contract start and end dates, volumes and cost information remain confidential and redacted before the Commission. The CCA Parties believe the IOUs are not complying with existing Commission decisions, including D.06-06-066, with regards to making contract information publicly available after 3-years' time. This lack of transparency continues to provide the IOUs with a competitive advantage over other LSEs, such as CCAs.

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[10] It is the CCA Parties' understanding that the IOUs present load and generation forecasts to the CEC to inform their IEPR process. It is also the CCA Parties' understanding that the IOUs present annually recorded production and cost information on a per resource basis through their Form 1 filings with FERC. CCAs do not currently have access to this forecast information.

Presently the CCA Parties, other CCAs, and local governments considering forming or participating in CCAs have almost no visibility into the drivers that influence the annual calculation of the PCIA rate. As highlighted during the 2016 PG&E ERRA proceeding by MCE's testimony, briefing, and comments,[11] CCAs have little opportunity to plan for and adjust to fluctuations in the PCIA rate. For example, it was not until November 2015 that MCE staff was able to access the information necessary to determine that PG&E sought to double the PCIA rate that the majority of MCE's residential customers pay (2012 vintage) effective January 1, 2016.[12]

Furthermore, as market participants, there is an excessive level of redacting applied to the information that CCA staff is able to attain from PG&E. For example, when MCE sought contract-specific information from PG&E through discovery, of the 275 contracts presented by PG&E as factoring into the PCIA calculation, MCE was only able to see the full information for seven. MCE therefore has incomplete information for over 97% of the contracts that are represented in the PCIA fee charged to its customers. MCE is undertaking efforts to meet and confer with PG&E staff to determine whether all of this information is appropriately redacted per D.06-06-066. MCE and other CCAs also do not have access to the information used to determine the Green Adder in the Market Price Benchmark ("MPB"), and IOU load information that materially impacts the annual PCIA calculation as well. As such, CCAs have no reasonable means to anticipate significant changes in the annual PCIA rate and plan accordingly. Furthermore, CCAs have no basis upon which to rely that the IOUs are ensuring the annual PCIA rate is just and reasonable.

11 *See* MCE's filings within A.15-06-001.

12 PG&E's November Update within A.15-06-001 was served on November 5, 2015 requesting rate changes effective 57 days later on January 1, 2016.

PROPOSED SOLUTIONS:

*i. __Solution:__ **The Pricing, Volumes and Term of Each of the IOUs' Contracts That Make up the PCIA Should Be Made Public Upon Approval of the Contract or Resource***

As a general matter, once a contract is signed with a CCA and approved for its procurement portfolio, that contract and all of its specifics (including price and output) are publicly available information. There are certain exceptions to this statement, but they are relatively limited. Some public agencies even provide information before contract execution as part of the administrative review process. For example, the city of Palo Alto discloses contractual information as part of its city council review process, including the full Power Purchase Agreement with contract rate information.[13] Similarly, MCE includes a report on approved contracts as part of its Board Packet, including information on contract amount and term.[14]

The CCA Parties recommend that the IOUs follow this same practice in order to allow proper vetting and full transparency. The CCA Parties are not alone in this recommendation. In a ruling with respect to the Renewables Portfolio Standard ("RPS") program, the Commission vetted a proposal by the CPUC Energy Division that sought to clarify and improve confidentiality rules for RPS-related contracts.[15] Under the Energy Division's proposal, for RPS procurement contracts that require Commission approval via resolution, the contract price must be publicly disclosed in the draft resolution (and the final resolution) approving the contract.[16]

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13 *See, e.g.,* Memorandum to City of Palo Alto's Utilities Advisory Commission from the Palo Alto Utilities Department, Attachment B (Jan. 13, 2016) (for power purchase agreement).

14 *See, e.g.,* MCE Board of Directors Meeting at Section 5(C)(2) (Jan. 21, 2016) (for an update on approved contracts).

15 *See Administrative Law Judge's Ruling Requesting Comments on Preliminary Staff Proposal to Clarify and Improve Confidentiality Rules for Renewables Portfolio Standard Program,* dated July 1, 2013, in R.11-05-005 ("RPS Ruling").

16 RPS Ruling at 20.

For RPS procurement contracts submitted for Commission approval via (non-Tier 3) advice letters, the contract price would be publicly disclosed at the time the advice letter is filed.[17] The CCA Parties encourage the Commission to reconsider the proposal advanced by the Energy Division.

ii. ***<u>Alternate Solution</u>: The Pricing, Volumes and Term of Each of the IOUs' Contracts That Make up the PCIA Should Be Made Public No Later Than One Year After Approval of the Contract or Resource***

In the event the IOUs can provide meaningful reasons why contract pricing, volumes, and/or terms should remain confidential immediately after execution or approval, the Commission should evaluate whether those rationales outweigh the benefits of transparency and accountability. The Commission may consider that contracts should be made public no later than one year after such execution or approval since much of the pricing and delivery information can be deduced from the IOUs' FERC Form 1 filings (at significant cost and burden for reviewers).

iii. ***<u>Alternate Solution</u>: The Commission Should Revisit Its Confidentiality Rules to Ensure All Information That Is Non-Confidential in Other Reports Is Non-Confidential Under CPUC Rules***

As discussed above, IOUs disclose information through the IEPR process, FERC Form 1 and other requirements. In order to ensure consistency with these other disclosure rules, the Commission should: (i) review the IOU presentation of both "public" and "confidential" information specific to the PCIA for compliance with present Commission rules; (ii) direct the IOUs to provide information specific to the PCIA that is available (although perhaps in different formats) in other public forums, such as the CEC and FERC; and (iii) revisit the rationale behind the current confidentiality rules to determine whether they are serving the public interest.

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[17] RPS Ruling at 23.

With regard to this latter point, the CCA Parties urge the Commission to reconsider the public interest policies that are promoted (or suppressed) by the Commission's current confidentiality rules. Thankfully, the Commission is seriously considering some of these matters in R.14-11-001. The Order Instituting Rulemaking ("Confidentiality OIR") in that proceeding echoes many of the same policy statements espoused by the CCA Parties – statements that warrant serious reexamination of the Commission's current confidentiality rules for the PCIA inputs. The following brief excerpt from the Confidentiality OIR underscores this point:

> Further, the Legislature has declared that "access to information concerning the conduct of the people's business is a fundamental and necessary right of every person in this state." An agency must base a decision to withhold a public record in response to a CPRA request upon the specified exemptions listed in the CPRA, or a showing that, on the facts of a particular case, the public interest in confidentiality clearly outweighs the public interest in disclosure. The CPRA favors disclosure, and CPRA exemptions must be narrowly construed. The fact that a record may fall within a CPRA exemption does not preclude the agency from disclosing the record if the agency believes disclosure is in the public interest. Unless a record is subject to a law prohibiting disclosure, CPRA exemptions are permissive, not mandatory; they allow nondisclosure but do not prohibit disclosure.[18] Alternate Solution: The Commission should adopt a third category under its confidentiality rules

iv. Alternate Solution: The Commission Should Adopt a Third Category Under Its Confidentiality Rules for Public Agency Participants

Presently the Commission's confidentiality rules consider just two types of participants engaging before the Commission: market participants and non-market participants. Much of the justification for the protections of information under these rules is to prevent manipulation and gaming by market participants that both compete with IOU's bundled electricity services and engage in selling electricity to the IOUs. In addition to revising the current confidentiality rules,

[18] Confidentiality OIR at 3 (internal citations omitted).

the Commission should also create a third category of participant to be considered within them: Public Agency Participants.

In the case of CCAs, CCAs are public agency market participants that compete with the IOUs' electricity generation services, but as a general rule CCAs *are not* engaged in the business of selling electricity to the IOUs. In addition, with the possible exception of a very large CCA, CCAs are not large enough to alter market prices. As such, the CCA Parties believe it would be reasonable to create a third category for the purpose of reviewing confidential material (Public Agency Participants). This category of market participant does compete with IOUs' bundled services and are impacted by the PCIA, but does not engage in wholesale seller's arrangements with the IOUs. As such, Public Agency Participants do not present the same level of risk for manipulation and should be permitted a higher level of access to information considered "confidential" under the present rules, subject of course to a non-disclosure agreement.

This approach comports with the unique status afforded the California Independent System Operator Corporation's ("ISO") Reviewing Representative under the Commission's Decisions. Presently, under the Model Protective Order provided in D.06-12-030, D.08-04-023, and clarified D.11-07-028, the ISO can review confidential information without violating confidentiality rules. The rationale for this unique approach for the ISO was first expressed in D.06-12-030, where the Commission distinguished the ISO from other market participants, noting that "Its incentive is…not to drive up (or down) the price of electricity out of a desire to enhance profits for itself" and that "the CAISO is more akin to a state agency than it is to a market participant."[19] CCAs are local agencies that, similar to the ISO rationale above, do not seek to enhance shareholder profits, and are primarily concerned with providing clean and

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[19] Decision 06-12-030 at 35, note 44.

reliable power. Thus, the Commission should consider allowing CCAs and other public agencies without a shareholder profit motive to review information while participating in the energy market, subject to a nondisclosure agreement.

v. ***Alternate Solution: The Commission Should Direct the IOUs to Provide 10-Year Forward Forecasts of Total Portfolio Costs and Percentage Breakdowns of RPS and Non-RPS***

Due to the present lack of transparency surrounding the PCIA methodology, the Commission should direct the IOUs to present CCAs and other non-IOU LSEs with a 10-year forecast of the IOUs' Total Portfolio Costs and volumes, by vintage, and the percentage renewable to non-renewable composition of this portfolio for each year. Such a projection will allow CCAs to approximate potential PCIA rates for coming years and conduct more reasonable long-term planning around the potential changes to the PCIA.

2. ENSURE NON-CONFIDENTIAL INFORMATION IS DISCLOSED

As discussed in Section 1 above, the IOUs have often taken the stance of using the confidentiality rules to protect information that is not confidential or market sensitive. This results in a lack of transparency and wasted time on the part of parties and the Commission to address meet and confer requirements and motions to compel.

PROPOSED SOLUTION:

i. ***Solution: The Commission should strongly and swiftly enforce rules and create consequences for failure to disclose non-confidential information***

In addition to reforming the confidentiality rules as discussed in Section 1, the Commission must enforce those rules and ensure that IOUs are appropriately disclosing non-confidential information. If the IOUs continue to obfuscate information through over-redaction when Commission policy clearly states such information should be made public, there should be direct consequences, including fees or penalties, as well as a requirement that the IOU reimburse impacted parties for time and resources spent preparing multiple requests, meet and confer sessions, and motions to compel.

3. ENSURE THAT THE TOTAL PORTFOLIO APPROACH EXCLUDES AVOIDABLE COSTS

The Commission has mandated that the PCIA must represent only the unavoidable[20] above-market stranded costs.[21] These costs must be unavoidable, above-market costs of the IOU electricity procurement portfolios that become stranded when load departs from that IOU's bundled electricity services to take electricity generation services from another LSE, such as an ESP or CCA. The PCIA is imposed to ensure that such departing load remains responsible for paying any procurement costs incurred on their behalf by the utility prior to the departure. The Commission has variously referred to this principle as the "fair share" principle, which has been summarized by the Commission as follows: "[T]he rule is that when costs are incurred on its behalf, that customer must pay its fair share of the costs. A corollary rule is that if no costs are incurred on its behalf, then the customer's fair share can be determined to be zero."[22]

It is in the IOUs' competitive interest to pad as many costs into the PCIA as possible because the PCIA directly reduces the margin that CCAs and other non-IOU LSEs have to compete with the IOUs' bundled electricity services. Since there is no transparency within the calculation and there is no clear means by which above-market costs are determined to be *avoidable* versus *unavoidable*, the CPUC must ensure that the IOUs are not leveraging the PCIA construct for their competitive advantage by assigning excessive and unnecessary procurement

[20] *See* California Public Utilities Code Section 366.2(f)(2)

[21] D.04-12-046 at 65.

[22] D.08-09-012 at 10-11.

costs to the PCIA. Without proper transparent review, there is no way to determine whether or not there are improper inclusions in the PCIA rate. Based on its response to MCE's recent discovery requests, it seems PG&E has taken no steps to mitigate the costs that factor into the PCIA. This is despite the fact that it is clearly the Commission's objectives to minimize the PCIA and promote good resource planning by the IOUs.[23]

Though both statute and Commission Decisions clearly state the PCIA should only include *unavoidable* above market costs,[24] the CCA Parties believe the present vintage "Total Portfolio"-based methodology[25] for determining the above market costs that factor into the PCIA does not fully consider what costs are avoidable and what are not. There are a number of strategies to employ to avoid above-market costs:

(i) Forecasting and planning around likely load departure (as D.15-10-031 directs) will reduce unavoidable costs due to CCA load departures;

(ii) Require an IOU to mitigate damages annually for Power Purchase Agreements ("PPAs"). For example, whenever an IOU has an option to extend, amend, renegotiate, terminate, reduce the duration, or reduce the volume of electricity purchased through a specific contract and the IOU chooses to exercise this option, then the costs associated with that resource should no longer be considered unavoidable for existing departed load because the IOU has chosen to retain the resource in light of the existence of this already departed load;

(iii) Require the IOUs to curtail generation from Utility-Owned Generation ("UOG") when resources with above-market costs are avoidable. If the IOU continues to generate

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[23] *See* D.04-12-046 at 29. ("Our complementary objective is to minimize the CRS…and promote good resource planning by the utilities.").

[24] *See* California Public Utilities Code Section 366.2(f)(2) *and* D.04-12-046 at 65.

[25] *See* PG&E's Opening Testimony – Chapter 9.

electricity beyond the minimum from this resource, then the costs of the curtailable portion of the resource's generation should be considered avoidable costs and not included within the PCIA calculation.

PROPOSED SOLUTIONS:

i. ***Solution: Ensure Proper Forecasting of CCA Departing Load Occurs in Accordance With D.15-10-031***

Though D.15-10-031 clearly directs for both PG&E and SCE to forecast for departing load due to CCAs over a 10-year horizon, this Decision fails to direct SDG&E to make similar forecasts despite strong interest in CCA formation being displayed within its service territory. As an aside, it is important to note that D.15-10-031 is not the first pronouncement on this matter. Assembly Bill ("AB") 1723 was passed by the Legislature *in 2005* for the purpose of quantifying the amount of forecasted departing load.[26] The purpose of AB 1723 is summarized as follows: "the purpose of this bill is to make public the IOUs' forecasts to determine whether the IOUs pre-purchased electricity on behalf of departing customers."[27] Unfortunately however, the Commission has given little practical effect to this law. Nevertheless, the Commission has repeatedly directed the IOUs to not rely on static, standardized assumptions regarding CCA departing load, but rather the IOUs are to employ dynamic means (informed by "information provided by the CEC and from other sources…") to "estimate reasonable levels of expected DA and CCA departing load…."[28]

Additionally, the implementation of this forecast and the consideration of how to address a scenario in which a forecast does not match the observed CCA load departures has yet to be

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26 *See* Stats. 2005, ch. 703, adding Section 25302.5 to the Public Resources Code.

27 *See* Assembly Bill Analysis of AB 1723, August 2005.

28 D.14-02-040 at 16. *See also* D.12-01-033 at 30.

discussed within the record of a Commission proceeding. If more load departs than was forecasted for in a certain year, will all the load that departs during that year be subjected to the stranded costs associated with this unexpected load departure? Or will only the segments of load departure that exceed the forecast be subjected to the PCIA for that specific vintage? The Commission must examine these issues and provide clear guidance so that going forward timely and accurate forecasts of CCA departing load can reduce the amount of *unavoidable* stranded costs due to CCAs' customers.

ii. __Solution__: Require the IOUs to Mitigate Damages Annually for PPAs

Mitigation of damages is a foundation of a wide range of areas of law.[29] As a general matter, the Commission has broad authority to disallow recovery of costs that are unreasonable.[30] If it truly is the Commission's objective to minimize the PCIA, promote good resource planning by the IOUs[31] and promote just and reasonable rates, then the Commission must require the IOUs to mitigate damages (i.e. the occurrence of above-market stranded costs) that factor into the PCIA. When presented with a reasonable opportunity to avoid the continuance of such above-market stranded costs, the Commission should direct the IOUs to act upon such

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29 *See, e.g., Agam v. Gavra*, 236 Cal. App. 4th 91, 111 (2015) ("The doctrine of mitigation of damages holds that a plaintiff who suffers damage as a result of … a breach of contract … has a duty to take reasonable steps to mitigate those damages and will not be able to recover for any losses which could have been thus avoided. Under the doctrine, [a] plaintiff may not recover for damages avoidable through ordinary care and reasonable exertion." (Internal citations omitted.)

30 *See, e.g., In Re Pac. Gas & Elec. Co.*, 199 P.U.R.4th 177 (Feb. 17, 2000) "Under Sections 701 and 728, the Commission has the authority to determine what is just and reasonable, and to disallow costs not found to be just and reasonable. In particular, the Commission 'has the power to prevent a utility from passing on to the ratepayers unreasonable costs for materials and services by disallowing expenditures that the commission finds unreasonable." (Internal citations omitted.)

31 D.04-12-046 at 29.

opportunities. Failure to do so will result in excessive costs for both bundled and unbundled ratepayers alike.

In order to ensure that the IOUs' are acting upon all of these opportunities to mitigate costs, the Commission should conduct an annual audit (perhaps as part of the annual ERRA compliance proceedings for each individual IOU) to determine whether the IOU has appropriately taken steps to mitigate avoidable above-market costs. For PPAs, this audit would consider whether the IOUs have had the option to extend, amend, renegotiate, terminate, reduce the duration, or reduce the volume of electricity purchased for each contract that factors into the IOU's PCIA calculation.

iii. Solution: Require the IOUs to Curtail Generation Annually From UOG When Above-Market Costs Are Avoidable

For UOG, this audit would consider whether generation from above-market UOG could be curtailed to any extend while still recovering the necessary amount of operational and sunk capital costs that need to be recovered in rates. For any instances where the IOU has failed to exercise its 'option' to avoid further above-market stranded costs associated with these resources, this failure to mitigate costs would result in a disallowance for the utility and the removal of these costs from PCIA rates.

4. SET CLEAR AND APPROPRIATE DURATION LIMITS FOR STRANDED COST RECOVERY

Current Commission policy is unclear at best regarding the duration limits for stranded cost recovery of conventional, renewable, and UOG resources. The Commission last addressed these policy matters in the 2004 Long-Term Procurement Plan ("LTPP") proceeding cycle with D.04-12-048. However upon closely examining this Decision, the policy guidance that it provides regarding stranded cost recovery appears self-contradictory and vague.

With regards to conventional resources, the dicta and Conclusions of Law ("COL") sections of D.04-12-048 seem to clearly intend for stranded cost recovery to occur "over either the life of the contract or 10 years, whichever is less."[32] Yet, Ordering Paragraph ("OP") 10 suggests a "15-year standard for new fossil-fueled resources acquired by the utilities."[33] While CCA Parties have conservatively interpreted D.04-12-048 to authorize the stranded cost recovery for conventional resources for no more than 10 years, the CCA Parties believe the IOUs may have come to a different conclusion based upon PG&E's response to discovery.[34]

With regards to renewable resources, there is vagueness regarding the upward limitations for stranded cost recovery. Though the dicta, COL, and OP in D.04-12-048 do seem to agree that for renewable generation stranded cost recovery should be allowed "over the life of the contract," yet it remains unclear to the CCA Parties what is the upwards limit for the life of a renewable contract. Dicta within D.04-12-048 suggests the life of renewable contracts span up to 20 years,[35] yet PG&E states within its response to MCE Data Request 003 Question 4 that it has at least renewable contract spanning 25 years.[36]

Lastly with regards to UOG, D.04-12-048 dicta and COL also suggest that stranded cost recovery is limited to 10-years, yet it seems to the CCA parties that in practice stranded costs

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[32] D.04-12-048 at 61, 63, and COL 16.

[33] D.04-12-048 at OP 10.

[34] *See* PG&E's Response to MCE Data Request 003 Question 4 (included within Appendix A of this document.)

[35] D.04-12-048 at 63 ("With regard to the long-term contracts for renewable generation called for by the legislature, we have previously authorized the utilities to enter into contracts with terms of up to 20 years order in order to encourage development of these resources.")

[36] *See* PG&E's Response to MCE Data Request 003 Question 4 (included within Appendix A of this document.)

associated with UOG resources are spanning longer than 10-years.[37] *As such the CCA Parties implore for the Commission to clearly define either prior to or at the March 8 workshop what the present limitations for stranded cost recovery are for conventional, renewable, and UOG resources.*

In addition to the significant uncertainty regarding the stranded cost recovery duration limits as authorized by the Commission, resource online dates vary tremendously as well. Due to both of these factors the resulting duration of cost recovery assigned to each specific vintage of departing load vary considerably. Based on PG&E's response to MCE's discovery it appears that this stranded cost recovery will span more than 30-years duration.[38] Considering that the IOUs' own long-term procurement planning is limited to 10-years, it is unreasonable for other LSEs to plan their procurement around a sizable fee that lasts three times the length of the IOUs' procurement planning horizon. The Commission has not significantly revised the duration of stranded cost recovery since D.04-12-048, and as stated above this Decision appears to contradictory itself.

Allowing for excessive stranded cost recovery under the PCIA is problematic for several reasons. First, the uncertain duration of the cost recovery on a per vintage basis is challenging to communicate to CCA customers. Second, it creates an unfair dynamic where non-IOU LSEs are forced to plan around a variable charge over a time horizon that is triple the duration of the IOUs' long-term planning horizon. Third, the special considerations that allow for the extension of stranded cost recovery beyond the standard up to10-year limit are no longer valid to spur

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[37] D.04-12-048 at 61 and COL 16.

[38] *See* PG&E Response to MCE Data Request 002 Question 1, indicating the PCIA stranded cost recovery period for current CCA customers in certain vintages will run until 2043. This also does not address the vintaging issue already in dispute within this proceeding (included within Appendix A of this document.)

renewable energy development and are no longer appropriate in light of the present maturity of the renewable electricity market.

PROPOSED SOLUTIONS:

i. Solution: Clarify Present Commission Policies on Stranded Cost Recovery

First off, the stranded cost recovery policy put forth in D.04-12-048 is self-contradictory and vague and must be clarified by the Commission prior to or at the March 8 workshop so that all engaging parties will have a common understanding of what present Commission policy on stranded cost recovery is for all three types of resources that factor into the PCIA calculation: conventional, renewable, and UOG. Such clarifications will likely help to both avoid and resolve disputes between the IOUs and non-IOU LSEs due to this contradiction and vagueness.

ii. Solution: Limit Stranded Cost Recovery to 10 Years for All Resource Types

Second, when the Commission determined in D.04-12-048 that it was appropriate to permit the stranded cost recovery for renewable resources via the PCIA for the life of the contract, the RPS mandate was a new creation and the renewable market was nascent. The Commission allowed life of contract stranded cost recovery because the Commission had "previously authorized the utilities to enter into contracts with terms of up to 20 years order in order to encourage development of these resources."[39] The period for special treatment of renewable resources contracted for or built by the IOUs has come to a close with prices for these resources approaching prices for conventional power.[40] Therefore, it is now appropriate to cap

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[39] D.04-12-048 at 63.

[40] *For example*, in January the Palo Alto City Council reviewed and approved a long-term contract for the purchase of renewable energy (solar photovoltaic) at a price of $36.76 per MWh. (https://www.cityofpaloalto.org/civicax/filebank/documents/50532)

(footnote continued)

stranded cost recovery for any new contracted or UOG renewable resources to the same "either the life of the contract or 10 years, whichever is less" policy limit that conventional resources are already limited to. This is reasonable and fair. Furthermore, this will significantly reduce the duration and uncertainty surrounding the duration of stranded cost recovery for future vintages of departing load.

5. LIMIT PCIA VOLATILITY AND UNCERTAINTY

The current PCIA methodology allows for too much volatility in the annual adjustment to the PCIA rate. As recently observed in the 2016 PG&E ERRA proceeding, the PCIA rate has the potential to shift dramatically from one year into the next.[41] As noted above, the 2016 PCIA rate for residential customers with a 2012 vintage nearly doubled relative the 2015 rate (95% increase). Such a tremendous change in a rate over a single year is unreasonable and puts non-IOU LSEs and their customers in an unfair circumstance where there is very little warning of the pending dramatic rate change.

PROPOSED SOLUTION:

i. Solution: Revise the MPB to Consider 5-Years of Natural Gas Prices

The CCA Parties believe a relatively simple way to dampen fluctuations in the PCIA annual rate adjustment would be to change the natural gas input price used to determine the MPB annually from a single year spot-market natural gas price to a multi-year average natural gas price. The natural gas price should be a 5-year average either based on a 5-year forward pricing curve (i.e. the average of the gas prices for the present year and four years beyond) or through an

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Also see Rhyne, I., & Klein, J. (May 2014). ESTIMATED COST OF NEW RENEWABLE AND FOSSIL GENERATION IN CALIFORNIA (CEC). Retrieved February 12, 2016, from http://www.energy.ca.gov/2014publications/CEC-200-2014-003/CEC-200-2014-003-SD.pdf

[41] *See* MCE's filings within A.15-06-001.

averaging to two prior years of historic gas prices with a 3-year forward pricing curve (i.e. the average of the gas prices for the present year with the two years prior and the two years beyond). This will dampen the sensitivity of the MPB calculation to large swings in the natural gas market from year to year. The CCA Parties believe this is a more reasonable approach because the IOUs are not required to sell excess power in the spot market, and instead have the option to sell off any excess above-market electricity through multi-year forward transactions.

6. DEVELOP ALTERNATIVES TO THE VOLATILE YEAR-BY-YEAR PCIA

Presently there is only one mechanism through which CCA customers and other types of departing load can repay their share of the utilities' unavoidable above-market stranded costs, a single, volatile and annually readjusted volumetric rate that varies somewhat with each vintage of departing load: the PCIA. The CCA Parties believe it is unreasonable and unjust the restrict non-IOU LSEs and their customers to repay these costs through only this one mechanism.

The PCIA calculation process is not transparent. This is compounded by the frequency of the rate change combined with the compressed procedural timeline for considering such rate changes. Therefore, this single annual rate is very challenging to plan around and explain to customers, elected officials and local community members. The non-IOU LSEs should be presented with multiple options—or a Menu of Options—for how their customers will be able to repay their share of unavoidable above-market stranded costs. CCAs and ESPs procure with distinctly different priorities (longer-term procurement vs. shorter-term procurement). CCAs and ESPs also cater to very different types of customers. As such it makes sense to allow for each non-IOU LSE to have options for differing mechanisms by which their customers will repay the unavoidable above-market stranded costs, as certain mechanisms may better fit the customer types and procurement practices of each distinct non-IOU LSE.

PROPOSED SOLUTION:

i. ***Solution:*** ***The Commission Should Provide a Menu of Options for Repayment***

The PCIA could be repaid simply through an up-front fixed valuation. This "lump sum" approach has been utilized for municipal departing load under various bilateral agreements with the IOUs.[42] In fact by negotiating and fixing the PCIA repayment responsibility for a specific vintage of customers served by a specific non-IOU LSE in an upfront manner, this would provide the non-IOU LSE with greater certainty and clearer communication to its customer base. The non-IOU LSE could then decide whether it would prefer to: (i) repay this upfront fixed valuation to the IOU in a lump-sum manner and then bear the responsibility of recovering these costs from its customer-base as it feels is appropriate; or (ii) work with the IOU to establish a balancing account for this fixed valuation and amortize the repayment of these costs through a fixed rate over a definite period of time (e.g. a fixed volumetric charge across all customer classes in that vintage of departing load applied to customers' bills over a 10 year period).

To determine this fixed valuation for a particular vintage of departing load, the IOU and non-IOU LSE would have to negotiate and agree to certain forward cost curves for renewable electricity, capacity, and conventional electricity products. In the end these projected costs could be higher or lower than actual costs, and the non-IOU LSE and its customers would bear that risk in exchange for certainty over their PCIA cost exposure. The CCA Parties envision this negotiation process would occur via a formal settlement process in accordance with Commission Rule 12. The fixed valuation for this particular segment of departing load, along with the fixed

[42] *For example*, Non-bypassable charge agreements were commended by the Commission in Resolution E-3999 as a possible way by which departing load charges could be fully and finally addressed on a lump sum basis. (*See* Resolution E-3999 at 44.) As a result, PG&E and SCE entered into numerous non-bypassable charge agreements. (*See, e.g.,* D.10-11-011 at 15. *See also* D.09-08-015.)

rate of repayment and the duration of the cost recovery if applicable, would be determined by the relevant IOU and non-IOU LSE(s) through this settlement negotiation to then be presented to the Commission for approval through an appropriate proceeding venue.

C. QUESTION 3: How should the CPUC address the potential departure from bundled service of a very large load, such as the City of San Diego or County of Los Angeles? Would transferring contractual responsibility from an IOU to a CCA be an option?

Before any sort of special treatment should be determined by the Commission for "very large" load departures, the Commission and parties must first establish a clear understanding with clear criterion for what is considered "a very large load." Even if all recommended revisions presented in response to question 2 are adopted, the PCIA would still be able to function properly for all types of departing load regardless of the size of the departure. The CCA Parties suspect the complexities of dealing with departing load depend more upon the IOUs' abilities to forecast and plan for such large load departures, than it depends on the mechanism for recouping costs that the IOU has already committed to. With that said, the CCA Parties largely defer to IOUs, Commission staff, and the representatives of the communities considering departing to form or join CCAs in a "very large load" manner to determine these circumstances the necessary special treatment.

The Commission staff may have difficulty addressing all of the potential issues raised by interested parties in response to these questions within a *single* workshop. As such, the CCA Parties recommend the discussion on this matter should be limited in the first workshop to reach a common understanding with clear criterion of what is considered "a very large load." The Commission could then address in a subsequent workshop what special treatment (such as potential transfer of contractual responsibilities) should be considered in instances where "a very large load" departure occurs.

As a final note, this is not the first time that the Commission has considered the issue of "large" in the context of departing load, and the Commission's past consideration of this issue may prove instructive in this context. In D.08-09-012, among other things, the Commission defined and applied departing load principles to so-called "large municipalizations." Importantly, as a general rule the Commission held that historical trends should be used to determine the amount of future departing load that will occur.[43] In the context of CCA programs, this means that the IOUs should take note of and plan for CCA departing load in a scale comparable to that which has occurred in recent years. The Commission went on to define "large municipalization" as follows:

> While there is no precise measure of what constitutes a "large municipalization," in the context of this decision, we are defining "large municipalization" as any portion of an IOU's service territory that has been taken control of or annexed by a POU where the amount of load departing the IOUs' service territories due to the municipalization is of such a large magnitude that it cannot reasonably be assumed to have been reflected as part of the historical MDL trends used in developing the adopted LTPP load forecasts.[44]

As a procedural matter, the Commission determined that "[i]mposition of new generation NBCs on customers departing due to large municipalizations shall be accomplished through a separate application filed by the affected IOU. Customers' NBC cost responsibility shall be determined through a fair share analysis based on the record of that proceeding. The IOU has the burden to show the departures are within the definition of a large municipalization, especially as it relates to how the large municipalization is or is not reflected in the adopted LTPP load forecasts."[45]

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43 D.08-09-012 at 27.

44 D.08-09-012 at 27.

45 D.-08-09-012 at 28-29.

D. QUESTION 4: Should Direct Access (DA) customers and Community Choice Aggregator (CCA) customers be treated differently vis-à-vis the PCIA? If so, why and how?

As part of its response to Question 2, the CCA Parties advocate for the Commission to allow for a "Menu of Options" for repayment of the PCIA. The CCA Parties believe this menu of options should be equally available to all entities serving departing load. While there are certain differences in the customer base and procurement practices of CCAs and DA,[46] the CCA Parties do not believe that any of the solutions previously presented in Question 2 are uniquely suited for CCAs.

As noted above, the nature of departing load is evolving and changing. In addition to ratepayers served by CCA and DA, departing load that is subjected to the PCIA includes participants in the Green Tariff programs and CGDL. The Commission should strive for PCIA reform that is both *fair* to all forms of departing load and *flexible* enough to enable LSEs to plan around the PCIA and effectively communicate the realities of the PCIA to their customers.

In its consideration of reforming PCIA, the Commission should consider whether the load has departed to procure cleaner electricity than is provided through the IOUs' bundled portfolio. *In these cases where load departs from bundled service to consume cleaner electricity, this departing load behavior is voluntarily accelerating the State's abilities to achieve is Climate Change goals. The CCA Parties believe such behavior should be supported, not restricted.* Presently the PCIA serves a barrier that inhibits all forms of departing load, regardless of whether the motives for the load departure do or do not align with the State's policy objectives.

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[46] *For example*, how customer vintages are determined and assigned under the PCIA for CCA and DA customers has already been presented within the record of this proceeding.

This is contrary to the Commission's historical application of departing load charges. In short, the Commission has balanced and harmonized the "fair share" cost responsibility requirements contained in AB 117 with other statutory provisions. For example, "despite apparent contrary language in AB 117, [the Commission] harmonized Public Utilities Code Section 366.2(d) with Public Utilities Code Section 353.2(b) to permit an exception for the payment of CRS for load involving ultra-clean and low-emission distributed generation."[47]

E. QUESTION 5: Can transparency regarding the calculation of the PCIA be increased while protecting valid interests in keeping certain information confidential?

As discussed in detail within the response to Question 2, the CCA Parties believe there is substantial need for improving the transparency of information used to calculate the PCIA, especially in the context of CCAs. The existing confidentiality process bars any meaningful review and evaluation of market sensitive information by CCAs, and makes the "meaningful public participation and open decisionmaking" mandated in Senate Bill 1488 (2004) difficult to accomplish. In the context of the PCIA, the restrictions on the review of information by market participants preclude any evaluation of whether the calculations performed by the IOU were performed accurately. CCAs are therefore unable to determine where the PCIA cost recovery requirement is presently and what changes will be made in the future.

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[47] D.03-04-030. D.03-04-030 is replete with policy-based explanations as to why cost responsibility charges should not apply to various distributed generation resources. The following is summary of these explanations: "On the basis of the policy preferences already articulated by the Legislature, as codified in recently enacted statutes, and by this Commission, however, we believe that there is sufficient policy basis to believe that customer generation confers a positive public benefit. Therefore, and consistent with these legislative policy directives, and in support of our policy preferences, we believe that we should apply CRS components differentially…." (D.03-04-030 at 45.)

Once deemed a market participant, a CCA is heavily restricted in its access to information. As explained in D.11-07-028, market participants can only access market sensitive information through the use of "reviewing representatives" who review the information under a non-disclosure agreement and retain the documents with strict confidentiality protections.[48] Among other things, a reviewing representative cannot be an employee of the market participant and a reviewing representative also cannot be engaged in electricity transactions at wholesale, bidding on power plants, or electricity marketing services. This restriction effectively screens out many qualified, independent consultants with industry expertise who are capable of readily understanding and reviewing the information provided. Even if a reviewing representative of a CCA did find important information pertinent to the purpose of the review, this information is under strict confidentiality protections and thus the findings of the review cannot even be disclosed to the CCA.

As discussed in Question 2 above, the CCA Parties propose several solutions to make information available. To the extent the solutions cannot be implemented in this proceeding, we recommend that the Commission include these modifications for discussion as part of the Commission's present efforts to improve access to information in Rulemaking 14-11-010.

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[48] *See* D.06-06-066.

IV. CONCLUSION

The CCA Parties thank Administrative Law Judge Tsen, Commissioner Florio and Energy Division staff for their attention to the matters discussed herein.

Respectfully submitted,

/s/ Jeremy Waen

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ON BEHALF OF
MARIN CLEAN ENERGY
AND CITY OF LANCASTER

February 16, 2016

APPENDIX A:

ATTACHMENT 1: Chapter 9 of PG&E's Opening Testimony for its 2015 ERRA Application

ATTACHMENT 2: Commission Resolution E-4475 – Exhibit A

ATTACHMENT 3: PG&E Response to MCE Data Request 002 – Question 1

ATTACHMENT 4: PG&E Response to MCE Data Request 003 – Question 4

ATTACHMENT 1:

Chapter 9 of PG&E's Opening Testimony for its 2015 ERRA Application

Application: 14-05-XXX
(U 39 E)
Exhibit No.:
Date: May 30, 2014
Witness(es): Various

PACIFIC GAS AND ELECTRIC COMPANY

PREPARED TESTIMONY

2015 ENERGY RESOURCE RECOVERY ACCOUNT AND GENERATION NON-BYPASSABLE CHARGES FORECAST

PUBLIC VERSION

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 9

2015 ENERGY RESOURCE RECOVERY ACCOUNT AND

GENERATION NON-BYPASSABLE CHARGES FORECAST

GENERATION NON-BYPASSABLE CHARGES

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 9
2015 ENERGY RESOURCE RECOVERY ACCOUNT AND
GENERATION NON-BYPASSABLE CHARGES FORECAST
GENERATION NON-BYPASSABLE CHARGES

TABLE OF CONTENTS

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 9
2015 ENERGY RESOURCE RECOVERY ACCOUNT AND GENERATION NON-BYPASSABLE CHARGES FORECAST
GENERATION NON-BYPASSABLE CHARGES

A. Introduction

This chapter discusses the calculation methodologies used to develop the procurement-related Non-Bypassable Charges (NBC) forecast in the Energy Resource Recovery Account (ERRA) Forecast Proceeding. Specifically, this chapter presents the derivation of revenue requirements for the 2015 Ongoing Competition Transition Charge (Ongoing CTC), Indifference Amount and related Power Charge Indifference Adjustment (PCIA), and the Cost Allocation Mechanism (CAM).

B. Commission-Adopted Market Benchmark

1. Background

The Market Price Benchmark (MPB) is used to calculate both the Ongoing CTC and PCIA revenue requirements. The difference between the average cost of the portfolio of resources, such as the total portfolio used in the PCIA calculation or the Ongoing CTC portfolio costs, and the market price benchmark reflects stranded or above market costs associated with the procurement portfolio. Thus, the revenue requirement is determined by comparing the ongoing CTC or total portfolio costs to an equivalent market-based portfolio, which is derived by multiplying the MPB value times the portfolio's forecasted generation in megawatt-hours (MWh). The resulting difference between the portfolio cost forecast and the market-based value for that portfolio forms the basis for the ongoing CTC or total portfolio indifference revenue requirements.

The MPB calculation starts with a foundation that was originally adopted in Decision 06-07-030, as modified by Decision 07-01-025. Specifically, the foundational portion of the benchmark calculation remains unchanged in that a portion of the benchmark using conventional gas-fired generation resources is calculated annually by the Energy Division (ED) based on the procedure described in Appendix 1 to Decision 06-07-030, as modified by

Decision 07-01-030 (Ordering Paragraph (OP) 2). That decision requires ED to:

- Collect daily forward price quotes from October 1 through October 31 for 12 months of on-peak (6 days × 16 hours/day) and off-peak (6 days × 8 hours/day; 1 day × 24 hours/day) power delivered at North of Path 15 (NP-15), as published in *Platts-ICE Forward Curve – Electricity* for NP-15.
- Average the daily quotes to get an annual on-peak forward price and an annual off-peak forward price.

As discussed below, the subsequent portions of the MPB calculation as originally described in Decision 06-07-030 were modified based on the directives in Decision 11-12-018, which were implemented, in part, in Resolution E-4475.

2. Total Portfolio Indifference and Benchmark Calculation Methodologies

In December 2011, the California Public Utilities Commission (CPUC or Commission) issued Decision 11-12-018, adopting revisions to the calculation methodologies for the total portfolio indifference calculation and to the MPB. The most significant revision was to the MPB calculation, which now includes a green adder that accounts for Renewables Portfolio Standard (RPS) eligible resources in the generation portfolio included in the indifference or Ongoing CTC calculations. The decision also included a modification to the capacity adder, which is now based in part on the composition of the resources in the portfolio.

The PCIA revenue requirement results presented in this chapter are consistent with Decision 11-12-018 and Resolution E-4475 directives with the exception that the updates for the green adder cannot be fully implemented until the November update, when data for all three Investor-Owned Utilities (IOU) becomes available. Both calculations and the new modifications are discussed in more detail below.

3. Resolution E-4475

Resolution E-4475, approved May 10, 2012, implements, in part, the method adopted in Decision 11-12-018 to account for the market value of RPS-compliance resources in the NBC applicable to departing load.

A description of the process by which the revised MPB will be calculated and updated annually, was memorialized in Exhibit A of Resolution E-4475. This resolution approved the Green benchmark, based on data submitted by the IOUs in compliance with Decision 11-12-018. The Green benchmark will be incorporated as a component into the final MPB used to calculate the relevant NBC on a vintaged basis. Exhibit A to Resolution E-4475 provides a detailed formula for the MPB calculation, which Pacific Gas and Electric Company (PG&E) includes as Attachment 9A to this chapter. This attachment provides the MPB components and the calculation methodology and process. The formula and process described in Resolution E-4475 at page 8 and the associated Exhibit A (Attachment 9A to this chapter) provide that:

- To incorporate the RPS adder into the MPB, on October 1 of each year, each utility files an advice letter, pursuant to OP 5 of Decision 11-12-018, to update their data, since, per OP 5, "The applicable percentage weightings [32 percent DOE Data and 68 percent utility data] are subject to relevant updated data in subsequent years." These advice letters may be designated as Tier 1, and any confidential data shall be protected from public disclosure, as provided in OP 4 of Decision 11-12-018.
- For receipt by early November of each year, ED purchases from Platt's (or another appropriate source) daily trading prices for the calendar month of October both for on-peak and off-peak periods for both North and South of Path 15. Using this data together with the shaping factors adopted in Decision 11-12-018, ED performs the MPB calculation as adopted in Decision 06-07-030 and compares its results with each utility's own calculation.
- Using the confidential data provided by the utilities in their October 1 advice letters on their RPS-compliant resources, the ED calculates the average energy cost of the utilities' RPS-compliant resources to incorporate into the MPB as adopted in Decision 11-12-018.
- Each utility then uses ED's results in its procurement forecast to compute specific MPBs by vintage and the applicable departing load cost responsibility surcharges.

4. 2015 Market Price Benchmark

The 2015 MPB used in this testimony was calculated based on the methodology described above. Due to the timing of PG&E's application filing, the MPB is an initial estimate of the 2015 result and relies on April forward market data, rather than October data as described in the relevant decisions. As a result, the forecast as presented in this testimony will be subject to an update, consistent with PG&E's November update of forward market prices and procurement costs, as well as the new requirement to submit a compliance advice letter on October 1 to update renewable data used to support the statewide Green benchmark results for the forecast year.

The initial estimated value, as presented in this testimony, utilizes the most recently approved Green benchmark price data for 2014 as a proxy for 2015. This result is combined with the peak and off-peak forward price data using April data, and the revised calculation methodology, as described below:

- Collect daily forward price quotes from April 1 through April 30, 2014, for 12 months of on-peak (6 days × 16 hours/day) and off-peak (6 days × 8 hours/day; 1 day × 24 hours/day) power delivered at NP-15 in 2014, as published in *Platts-ICE Forward Curve – Electricity* for NP-15.
- Average the daily quotes to get an annual on-peak forward price and an annual off-peak forward price.
- Determine a weighted average forward power cost for 2015 by multiplying the average on-peak and off-peak price times the weighting factors adopted in Decision 11-12-018, which are based on the most recent publicly available peak and off-peak bundled load weighting.
- Add a resource adequacy (RA)/capacity cost to the forward price based on the net qualifying capacity value in the portfolio, which is derived as:
  - **Capacity (CAP) ADDER** = {Sum of Net qualifying Capacity for all resources in the Utility Retained Generation (URG) Total Portfolio for PCIA Vintage year *v* * CAP VALUE)/forecast of the sum of MWh supplied by URG Total Portfolio for PCIA Vintage year *v*}; where

- **CAP VALUE** = the going forward cost (sum of insurance, *ad valorem* and fixed operations and maintenance costs) of a combustion turbine as determined per the most recent California Energy Commission's *Comparative Costs of California Central Station Electricity Generation Report* for a small simple cycle merchant plant.

- Add a line loss factor. The line loss factor accounts for delivery losses from NP-15 to load centers and is applied to the sum of the forward price cost, the weighted average green benchmark results, and the capacity adder to arrive at the final MPB value for each vintage portfolio. Decision 07-01-030 set the line loss factor at 6.0 percent for PG&E which remained unchanged in Decision 11-12-018, as described in Resolution E-4475.

5. Final Market Price Benchmark Calculation

As described in Attachment 9A (Exhibit A of Resolution E-4475), ED calculates the "BROWN and GREEN elements" in the MPB formula, based on inputs provided by each IOU in its respective October Compliance Advice Letter. Once ED provides these elements, the IOUs calculate the MPB for each vintage, based upon the "GREEN and BROWN values," the "CAP Value" above, and provide the calculations to ED for verification.

PG&E uses ED's updated inputs in the November Update annual forecast. As described above, for this testimony, PG&E is relying on the 2014 GREEN element as a proxy for 2015 and April forward price data, both of which will be updated in PG&E's November update testimony. The resulting estimate for the vintage MPBs are presented in Table 9-1.

C. Non-Bypassable Charges – Currently Effective Calculation Methodology

1. Ongoing Competition Transition Charge Forecast Revenue Requirement

The purpose of Ongoing CTC is to recover uneconomic costs resulting from California's electric industry restructuring from all consumers responsible for those costs. The Ongoing CTC represents above-market costs associated with eligible Qualifying Facility (QF) contracts and Power Purchase Agreement (PPA) restructuring costs, and other costs as authorized by the Commission. The Ongoing CTC is to be collected from all existing and future consumers as of December 20, 1995,[1] for all power purchase contract costs included in CPUC rates as of that date.[2] The calculation of Ongoing CTC follows the same "statutory method" presented in each of PG&E's ERRA applications since 2004. The statutory method refers to Pub. Util. Code Section 367(a)(1)-(6), which specifies the costs to be included in the above-market calculation. Use of the statutory method was clarified by the Commission in Decision 05-12-045.[3]

PG&E's pre-1996 contracts include agreements with QFs, Irrigation Districts and Water Agencies (ID&WA), the Metropolitan Water Agency, and the City and County of San Francisco. Most, but not all, of PG&E's QF contracts are CTC-eligible. Because energy payments to QFs are in proportion to natural gas prices, PG&E executes financial hedges against these costs as discussed in Chapter 8, "Hedging and Collateral Costs." The costs or benefits of these hedges are considered a part of QF purchase costs and thus are included in the above-market calculation.

The above-market cost for Ongoing CTC-eligible contracts is the difference between their total cost and the cost if the same volume of electricity MWh were purchased at the MPB $/MWh. The MPB is discussed in Section B. Costs associated with CPUC-approved QF contract restructurings are added directly to the above-market cost to produce the total Ongoing CTC cost. PG&E presents its 2015 Ongoing CTC revenue requirement calculation in Table 9-2.

Ongoing CTC-eligible contract costs are presented on lines 1 through 7, including line losses. Line 8 shows the market value of these resources. Line 9 reflects the difference between line 7 and line 8, which is the above-market portion of PG&E's legacy QF and ID&WA contracts. The ongoing CTC revenue requirement of $83.2 million is presented on line 14

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1 Public Utilities Code (Pub. Util. Code) § 369.

2 Pub. Util. Code § 367.

3 Decision 05-12-045, in PG&E's 2006 ERRA and Ongoing CTC revenue requirement proceeding, explicitly adopted the "statutory" method for calculating the Ongoing CTC, see OP 6, which in part states, "Ongoing CTC shall be calculated in accordance with the statutory method described in the body of this Order… ."

and includes franchise fees and uncollectibles (FF&U) and the expected year-end 2014 MTCBA balance.

2. Total Portfolio Indifference and the Power Charge Indifference Amount

This testimony presents PG&E's indifference calculations for forecast year 2015 for non-exempt Direct Access (DA) and Departing Load (DL) as defined in Decisions 06-07-030, 07-01-025, 08-09-012 and 11-12-018, and Resolution E-4475.

Decision 06-07-030 adopted an indifference calculation specifically to recover stranded costs associated with the California Department of Water Resources (CDWR) contracts. The indifference amount was determined by comparing the MPB value, as prescribed in Appendix 1 of that decision, with the average cost of the utilities' total portfolio, including both utility retained generation power and allocated CDWR power costs, to determine the level of the indifference charge. As described above, the MPB described in this decision has been modified by Decisions 11-12-018, implemented through Resolution E-4475.

In Decision 04-12-048, the Commission provided for stranded cost recovery in the form of a NBC to be paid by customers when they elect DA service, depart to be served by a Community Choice Aggregator (CCA), or elect another DL option. The NBC would be determined based on the timing of the customers' departure (i.e., customer vintage) and the date of the new generation resource commitment. Decision 08-09-012 approved the final calculation methodology associated with the new generation resource commitments authorized in Decision 04-12-048 which was a modified version of the indifference calculation approved in Decision 06-07-030. The Decision 04-12-048 PCIA would be applicable to departing customers not exempt from the NBC associated with the new generation resources as defined in the September 2008 decision. The modified indifference calculation includes the addition of new generation resource to each utility's total portfolio of resources, by vintage.

3. Calculation of the Indifference Amounts

a. Decision 06-07-030 Total Portfolio Indifference

The Decision 06-07-030 PCIA includes generation costs for resources in PG&E's portfolio prior to 2001/2002, often referred to in Decision 06-07-030 as "old-world" generation resources. More specifically, this calculation was established to collect stranded costs associated with the CDWR power contracts. PG&E has one remaining CDWR contract which is eligible for stranded cost recovery pursuant to Decision 06-07-030 and this contract will expire in September 2015. As a result, the PCIA associated with the CDWR power charge will end or be set to zero effective October 1, 2015.

The indifference calculation includes PG&E's total portfolio generation cost and gigawatt-hour (GWh) of generation, as described in Decision 06-07-030 and is the sum of:

1) PG&E's estimated CDWR Power Charge revenue requirement.
2) PG&E's old world generation revenue requirement.

The average cost of PG&E's total portfolio is compared to the market value to determine the level of the indifference for this portfolio of contracts. The MPB value is derived by multiplying the Pre-2009 MPB, discussed in Section B, by the total portfolio generation in GWh. Table 9-3 shows the 2015 indifference results for PG&E's total portfolio Decision 06-07-030 indifference calculation, on line 6.

The indifference result on line 6 reflects whether the portfolio costs are above or below market. Below market costs are negative and would be tracked to offset a future year's above market results. Above market costs are positive and would be combined with negative results from prior years to determine a cumulative Indifference amount.[4]

For 2015, the above market result is shown on line 6 and is combined with the negative results from prior years, shown on line 7. The cumulative indifference amount for 2015 is shown on line 8.

The equation to determine the PCIA revenue requirement is:

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4 Negative results will be tracked in the Negative Indifference Amount Memorandum Account.

Indifference = Ongoing CTC + PCIA

or

PCIA = Indifference – Ongoing CTC

If the cumulative indifference is less than or equal to zero, in the equation, Indifference is set to zero and solving for PCIA, the equation becomes:

PCIA = – Ongoing CTC

The indifference amount used to set the 2015 PCIA rate is presented on line 12 of Table 9-3.

b. Decision 04-12-048 Total Portfolio Indifference Calculation

The total portfolio indifference calculation for non-exempt departing customers that departed during or after 2009 includes the "old-world" generation costs discussed above as well as new generation resource commitments as authorized in Decision 04-12-048.

In addition to including new generation resource commitments, the total portfolio indifference calculation for this group of departing customers is vintaged such that new generation resource commitments are included in the total portfolio calculation based on the year the commitment was made.

The 2015 forecast indifference amount includes PG&E's total portfolio generation cost and GWh of generation, by vintage, as the sum of:

1) PG&E's estimated CDWR Power Charge revenue requirement.
2) PG&E's forecast for its old world resources.
3) PG&E's post-2002 resource commitments, as applicable, by vintage.

The average cost of PG&E's total portfolio, by vintage, is compared to the MPB value to determine the level of the indifference for each vintaged portfolio. The MPB values for each vintage portfolio are derived by multiplying the vintage portfolio's MPB as described in Section B, by the portfolio's generation in GWh, shown on line 2.

Similar to the Decision 06-07-030 calculations, the indifference result on line 6 reflects whether the portfolio costs are above or below market. Below market costs are negative and would be tracked to offset a future year's above market results. Above market costs are positive and would be combined with negative results from prior years to determine a cumulative Indifference amount.

For 2015, the above market result is shown on line 6. For Vintages 2009 through 2015, there are no negative results from prior years, and thus, the cumulative indifference amount for 2015 shown on line 6 is repeated on line 8.

The equation to determine the PCIA revenue requirement is:

Indifference = Ongoing CTC + PCIA

or

PCIA = Indifference – Ongoing CTC

The indifference amount used to set the 2015 Vintaged PCIA rate is presented on line 12 of Table 9-3.

c. Power Charge Indifference Amount Revenue Requirement

PG&E calculates the PCIA revenue requirement for non-exempt departing customers by utilizing the PCIA rate which is developed based on system-level power charge indifference revenue requirements shown on Table 9-3, line 12. Specifically, the PCIA rates are multiplied by the non-exempt DL to generate a forecast for the respective Decision 06-07-030 or Decision 04-12-048 PCIA revenue requirements. The Decision 06-07-030 PCIA revenue requirement is negative and reflects a credit of $2.9 million to non-exempt load that departed prior to 2009. This departing load credit will be a debit (cost) to bundled customers in ERRA. The Decision 04-12-048 PCIA revenue requirement is positive and reflects a cost of $50.2 million to non-exempt departing customers that depart bundled service between 2009 and 2015. This departing load cost will be a credit to bundled customers in ERRA.

4. Cost Allocation Mechanism

The CAM charge was initially authorized in Decision 06-07-029 and the methodology by which it was to be calculated was determined in Decision 07-09-044, which approved specific guidelines to be used to develop the CAM revenue requirement and resulting rate and provide for a true-up of this rate to actual costs. Subsequently, a CAM approach was adopted in Decision 10-12-035 for certain contracts arising from the Qualifying Facility and Combined Heat and Power (QF/CHP) Settlement approved in that decision. CAM treatment was also approved for the Marsh Landing PPA approved in Decision 10-07-045.

Under the CAM approach, certain costs and benefits are allocated among all load serving entities in the IOU's service territory. The allocated benefits include RA benefits. The load serving entities' customers receiving the RA benefit pay the net cost of this capacity, determined as a net of the total cost of the contract minus the energy revenues associated with dispatch of the contract.

The CAM charge was first included in forecast year 2012, as a result of the QF/CHP Settlement. For the 2015 Forecast, the CAM includes new CHP generation authorized under the QF/CHP Settlement and the Marsh Landing PPA, which was authorized for CAM treatment in Decision 10-07-045.

Chapter 3 of PG&E's testimony has costs related to the Marsh Landing PPA and Chapters 3 and 5 of PG&E's testimony have forecasts related to actual and expected CHP contracts costs and MWh that are eligible for recovery under the terms of the QF/CHP Settlement and OP 3 of Decision 10-12-035.

The CAM revenue requirement presented in this chapter adheres to the guidelines approved in Decision 07-09-044, which were included as Appendix A to that decision. Specifically, Appendix A included a "Joint Parties' Proposal" that articulated a calculation methodology to determine the market value of the resource.[5] The basic idea is that the cost of the resource minus the *value* of the energy and ancillary services results in a net capacity cost that is then allocated to all benefiting customers.

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5 Decision 14-02-040, OP 3, in Rulemaking 12-03-014, eliminated the Energy Auction originally approved in Decision 07-09-044 as the primary mechanism to determine market revenues associated with reliability resources. OP 3 states, "Energy auctions shall no longer be used to net capacity costs for facilities subject to the Cost Allocation Mechanism. Instead Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company shall use the mechanism adopted in Decision 07-09-044, known as the "Joint Parties' Proposal," to set the residual capacity costs that would be allocated to benefitting customers.

Attachment 9B to this chapter reproduces Section IX of Appendix A to Decision 07-09-044, which details the "Implementation Joint Parties' Proposal."

Generally, the methodology provides for developing a forecast of the relevant contract costs, then determining the value that resource's generation would have in the California Independent System Operator (CAISO) day-ahead market. The net results of the individual contracts are summed, and the total determines the net capacity costs that would be allocated to bundled, DA, CCA, and other DL customers.

This forecast of the net capacity costs is then used to set the CAM rate, which is discussed in Chapter 11. The forecast will be trued-up to actual costs by recording actual contract costs and the value of the generation based on the CAISO hourly day-ahead nodal price for the PPA's "injection point." The balance in the balancing account would then be amortized at the end of the year and incorporated into next year's forecast rate.

The CAM results are presented in Table 9-4 and result in a revenue requirement of $219.5 million.

D. Conclusion

PG&E requests that the Commission adopt PG&E's NBC forecast revenue requirements as follows:

1) Ongoing CTC revenue requirement of $83.2 million, presented in Table 9-2.
2) Decision 06-07-030 PCIA 2015 revenue requirement credit of $2.9 million associated with CDWR stranded costs, as described in Section C.3.a above.
3) Decision 04-12-048 PCIA 2015 revenue requirement forecast of $50.2 million associated new generation resources as described in Section C.3.b above.
4) CAM revenue requirement of $219.5 million presented in Table 9-4 and described in Section C.4.

PG&E requests that the Ongoing CTC and PCIA revenue requirements be updated in the November update, consistent with the scheduled adopted for the proceeding, and the balancing account balances will be updated one last time in December for implementation through the Annual Electric True-Up on or after January 1, 2015.

TABLE 9-1
PACIFIC GAS AND ELECTRIC COMPANY
2015 VINTAGED MARKET PRICE BENCHMARK

Line No.	2015 Forecast Year		2015 Portfolio TBCC Adders ($/MWh)	Pre-1996 Ongoing CTC ($/MWh)	Pre-2002 D.06-07-030 PCIA ($/MWh)	2015 Forecast by Vintage 2009 D.04-12-048 PCIA ($/MWh)	2010	2011	2012	2013	2014	2015
1	Forward Price Location			NP15	NP15	NP15	NP15	NP15	NP15	NP15	NP15	NP15
2	Average Prices from October Postings			PG&E	PG&E	PG&E	PG&E	PG&E	PG&E	PG&E	PG&E	PG&E
3	On Peak			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4	Off Peak			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
5	Publication: Platts ICE											
6												
7												
8	On-peak weighting			62.00%	62.00%	62.00%	62.00%	62.00%	62.00%	62.00%	62.00%	62.00%
9	Off-peak weighting			38.00%	38.00%	38.00%	38.00%	38.00%	38.00%	38.00%	38.00%	38.00%
10												
11	Calculated Baseload Price			$ 45.14	$ 45.14	$ 45.14	$ 45.14	$ 45.14	$ 45.14	$ 45.14	$ 45.14	$ 45.14
12	Capacity Adder	TBCC	$ 10.27	$ 8.52	$ 10.59	$ 10.90	$ 10.68	$ 10.67	$ 10.64	$ 12.01	$ 12.01	$ 12.01
13												
14	Subtotol Before Line Loss			$53.66	$55.73	$56.04	$55.82	$55.80	$55.77	$57.15	$57.15	$57.15
15												
16	Line Loss			1.060	1.060	1.060	1.060	1.060	1.060	1.060	1.060	1.060
17												
18	**Brown Market Price Benchmark, by Vintage**			**$56.88**	**$59.07**	**$59.40**	**$59.17**	**$59.15**	**$59.12**	**$60.58**	**$60.58**	**$60.58**
19												
20												
21	**Renewable Premium**											
22	Green Benchmark - Energy Division		$ 128.09									
23	less Brown Power BM (no capacity value, see line 11)		$ 45.14									
24	IOU RPS Premium		$ 82.95									
25												
26	PD Weighting											
27	)U 2015 RPS Premium, delivered energy $82.95/MWh @	68%	$ 56.41	$ 56.41	$ 56.41	$ 56.41	$ 56.41	$ 56.41	$ 56.41	$ 56.41	$ 56.41	$ 56.41
28	DOE REC Value $16.45/MWh @	32%	$ 5.26	$ 5.26	$ 5.26	$ 5.26	$ 5.26	$ 5.26	$ 5.26	$ 5.26	$ 5.26	$ 5.26
29	Weighted Average Renewable Premium		$ 61.67	$ 61.67	$ 61.67	$ 61.67	$ 61.67	$ 61.67	$ 61.67	$ 61.67	$ 61.67	$ 61.67
30												
31	Renewable Percentage in Portfolio		28.5%	34.0%	11.0%	28.5%	34.6%	36.04%	37.0%	37.1%	37.1%	37.1%
32	**Renewable Adder, by Vintage**	**TBCC**	**$ 17.56**	**$ 20.96**	**$ 6.76**	**$ 17.57**	**$ 21.32**	**$ 22.22**	**$ 22.81**	**$ 22.90**	**$ 22.90**	**$ 22.90**
33												
34	Revised MPB at Generator			$74.62	$62.48	$73.61	$77.14	$78.03	$78.58	$80.05	$80.05	$80.05
35	Line Loss			1.060	1.060	1.060	1.060	1.060	1.060	1.060	1.060	1.060
36	MPB with Renewable Premium, by Vintage			**$79.09**	**$66.23**	**$78.02**	**$81.77**	**$82.71**	**$83.29**	**$84.85**	**$84.86**	**$84.86**

Note: Totals may not add due to rounding.

TABLE 9-2
PACIFIC GAS AND ELECTRIC COMPANY
2015 ONGOING CTC FORECAST REVENUE REQUIREMENT

Line No.	Description	(MWh)	(GWh)	($000)
1	Qualifying Facilities (CTC-Eligible)		[redacted]	[redacted]
2	Gas Hedging for QF Short-Run Avoided Cost Payments			[redacted]
3	Metropolitan Water District		28	[redacted]
4	Irrigation Districts and Water Agencies		[redacted]	[redacted]
5	Total		7,055	$531,934
6	6% Line Loss		(423)	
7	Net Pre-1996 Contracts (Lines 5-6)		6,632	$531,934
8	Market Benchmark Cost	$79.09	6,632	524,501
9	Above-Market Costs (Line 7– Line 8)			$7,433
10	Ongoing CTC Costs			$7,433
11	FF&U at 0.01226			91
12	Ongoing CTC Revenue Requirement			7,525
13	Year-End 2014 MTCBA Balance (Including FF&U)			75,717
14	Total 2015 Ongoing CTC Revenue Requirement			$83,242

Note: Totals may not add due to rounding.

TABLE 9-3
PACIFIC GAS AND ELECTRIC COMPANY
2015 INDIFFERENCE CALCULATION

		Decision 06-07-030 PCIA	Decision 04-12-048 PCIA						
Line No.	2015 Annual ERRA Forecast	Pre-2009 Vintage	2009 Vintage	2010 Vintage	2011 Vintage	2012 Vintage	2013 Vintage	2014 Vintage	2015 Vintage
1	Total Portfolio Generation at Generator (GWh)	34,327	56,106	59,279	60,716	62,825	62,982	62,984	62,984
2	Total Portfolio Generation at Customer Meter (Includes Line Losses) (GWh)	32,268	52,739	55,722	57,073	59,055	59,203	59,205	59,205
3	Total Portfolio Cost ($1,000)	$2,248,778	$4,912,686	$5,398,045	$5,582,400	$5,765,558	$5,829,622	$5,829,841	$5,829,841
4	Benchmark ($/MWh)	66.23	78.02	81.77	82.71	83.29	84.85	84.86	84.86
5	Market Cost ($1,000)	2,137,083	4,114,725	4,556,416	4,720,521	4,918,706	$5,023,354	5,024,141	5,024,141
6	Current Year Indifference (Line 3 – Line 5)	$111,694	$797,961	$841,629	$861,879	$846,852	$806,268	$805,700	$805,700
7	2014 Cumulative Indifference	(1,191,206)	–	–	–	–	–	–	–
8	2015 Cumulative Indifference = (Prior Year(s) + Current Year Results))	(1,079,512)	797,961	841,629	861,879	846,852	806,268	805,700	805,700
9	2015 Cumulative Indifference With FF&U	$(1,092,746)	$807,744	$851,947	$872,445	$857,234	$816,153	$815,577	$815,577
10	Ongoing CTC Cost Revenue Requirement (RRQ)	7,525	7,525	7,525	7,525	7,525	7,525	7,525	7,525
11	Ongoing CTC End-of-Year (EOY) MTCBA Balance	75,717	–	–	–	–	–	–	–
12	PCIA Revenue Requirement for Rate Calculation(a) = Indifference – Ongoing CTC = (Line 9 – (Line 10 + Line 11))	$(83,242)	$800,220	$844,423	$864,921	$849,710	$808,629	$808,053	$808,053

(a) PCIA revenue requirements in Chapter 1 and 10 are imputed based on PCIA rate times non-exempt load.

Note: Totals may not add due to rounding.

TABLE 9-4
PACIFIC GAS AND ELECTRIC COMPANY
2015 COST ALLOCATION MECHANISM (CAM) FORECAST REVENUE REQUIREMENT

Line No.	Costs ($000s)	2015 Total CAM
1	Costs	$384,390
2	Revenue	(156,324)
3	CAM Results	228,066
4	Total CAM Revenue Requirement	230,862
5	New System Generation Balancing Account (NSGBA) EOY Balance	(11,316)
6	Total CAM RRQ	$219,546

Note: Totals may not add due to rounding.

Attachment 2:

Commission Resolution E-4475 – Exhibit A

Exhibit A

Proposed Formula to Calculate the Market Price Benchmark per D.11-12-018

Revised MPB for year *n* and Vintage Total Portfolio v= { (1-RPS%$_V$) x BROWN + (RPS% $_V$) x GREEN + CAP ADDER $_V$} x (LOSSES)
n = year covered by the calculation, e.g. n=2012 for the MPB for 2012.
v = PCIA vintage year
RPS% = The fraction of RPS compliant electric energy in the URG [Utility Resource Generation] Total Portfolio[6] for PCIA Vintage year *v* in year *n*.

BROWN = Weighted average of peak and off-peak forward prices for year *n*, weighting based on, for each IOU, the IOU bundled load profile data for the most recent year that is publicly available. Peak and off-peak forward prices based on published data for NP15/SP15 as per D.06-07-030. ($/MWh)

GREEN = 0.68 x URGgreen + 0.32 x (BROWN + DOEadder)
Where:
URGgreen = {[Forecasted cost in year *n* of RPS power contracts and IOU-owned projects starting deliveries in year *n* and *n-1*] - [NQC[7] of those contracts/projects*CAP VALUE]}/[Total forecasted deliveries from those contracts in year *n*] ($/MWh)
The forecasted cost of all Renewable Energy Credit (REC)-only contracts will also include the cost of energy associated with those REC-only contracts, equal to BROWN x forecasted deliveries from those REC-only contracts in year *n*.

DOEadder = Simple average of the premiums of the renewable programs in states within Western Electricity Coordinating Council (WECC), as identified in the database compiled by the National Renewable Energy Laboratory for the US Department of Energy. If multiple premiums are identified for the same utility and/or program, all shall be included in the average. ($/MWh)

[6] Per D.07-07-030 and D.08-09-012

[7] Net Qualifying Capacity

CAP ADDER = {Sum of NQC for all resources in the URG Total Portfolio for PCIA Vintage year *v* * CAP VALUE)/forecast of the sum of MWh supplied by URG Total Portfolio for PCIA Vintage year *v*}

CAP VALUE = the going forward cost (sum of insurance, ad valorem and fixed operations and maintenance costs) of a combustion turbine as determined per the most recent California Energy Commission (CEC) *Comparative Costs of California Central Station Electricity Generation Report*[8] for a small simple cycle merchant plant.

Per Table 4 of 2010 CEC report,

Insurance:	$9.63 per kW-year
Ad Valorem:	$13.09 per kW-year
Fixed O&M:	$27.45 per kW-year
Total Going Forward Costs (CAP VALUE):	$50.17 per kW-year

LOSSES = Line loss factors per D.07-01-030: PG&E 1.06; SCE 1.053; SDG&E 1.043

The Energy Division would calculate the **BROWN** and **GREEN** elements to the formula, based on inputs provided by each IOU. The IOUs would calculate the Market Price Benchmarks for each Vintage, based upon the **GREEN** and **BROWN** values provided by Energy Division, the **CAP VALUE** above, and the RPS percentages, NQCs and energy of each URG Total Portfolio. These calculations would be provided to Energy Division for verification.

[8] http://www.energy.ca.gov/2009publications/CEC-200-2009-017/CEC-200-2009-017-SF.PDF

ATTACHMENT 3:

PG&E Response to MCE Data Request 002 – Question 1

PACIFIC GAS AND ELECTRIC COMPANY
Energy Resource Recovery Account 2015 – Forecast
Application 14-05-024
Data Response

PG&E Data Request No.:	MCE_002-Q01		
PG&E File Name:	ERRA-2015-PGE-Forecast_DR_MCE_002-Q01		
Request Date:	December 23, 2015	Requester DR No.:	002
Date Sent:	January 6, 2016	Requesting Party:	Marin Clean Energy
PG&E Witness:	Donna Barry	Requester:	Jeremy Waen/Elizabeth Kelly

SUBJECT: POWER CHARGE INDIFFERENCE ADJUSTMENT (PCIA)

QUESTION 1

For each PCIA customer vintage, beginning with 2010 and continuing through 2016, please provide the expected dates on which PG&E will no longer collect PCIA charges from the customers included in each vintage.

ANSWER 1

The following forecasted end dates for the Power Charge Indifference Adjustment (“PCIA”) are based on current expiration dates of the contracts applicable to each vintage. The actual end date may vary. In addition, while the PCIA may still exist through these dates for a particular vintage, the PCIA amount in any given year could be $0 or negative up to the level of the ongoing Competition Transition Charge (“CTC”) if the portfolio costs are below-market or if a positive indifference amount is offset by an accrued negative indifference amount for a particular vintage.

Vintage	**Forecasted End Date of PCIA**
2010	December 2041
2011	December 2041
2012	December 2043
2013	December 2043
2014	December 2043
2015	December 2043
2016	December 2043

ATTACHMENT 4:

PG&E Response to MCE Data Request 003 – Question 4

PACIFIC GAS AND ELECTRIC COMPANY
Energy Resource Recovery Account 2015 – Forecast
Application 14-05-024
Data Response

PG&E Data Request No.:	MCE_003-Q04		
PG&E File Name:	ERRA-2015-PGE-Forecast_DR_MCE_003-Q04		
Request Date:	January 28, 2016	Requester DR No.:	003
Date Sent:	February 11, 2016	Requesting Party:	Marin Clean Energy
PG&E Witness:	Donna Barry	Requester:	Jeremy Waen/Elizabeth Kelly

SUBJECT: POWER CHARGE INDIFFERENCE ADJUSTMENT (PCIA)

QUESTION 4

In its response to Question 1 of MCE's prior data request, PG&E states that it anticipates the present vintages of CCA departing load to be responsible for paying back the PCIA through either 2041 or 2043 depending upon their respective vintages. Furthermore, conventional power purchase contracts are limited to 10 years of stranded cost recovery under the PCIA while renewable contracts are limited to the life of the contract (which is capped at 20 years) for stranded cost recovery under the PCIA. With these facts in mind please answer the following questions:

Please explain why PG&E's forecasted end dates for PCIA cost recovery span approximately 30 years from the creation date of each customer vintage.

ANSWER 4

The question suggests that stranded cost recovery for renewable contracts are "limited to the life of the contract (which is capped at 20-years) . . . ." Renewable contracts are recoverable for the life of the contract pursuant to D.04-12-048. See Conclusion of Law 16 and Ordering Paragraph 10:

> **COL 16, in part**
>
> . . . Stranded costs arising from RPS procurement activities should be collected from all customers, including departing load, over the life of the contract . . .
>
> **OP 10**
>
> We adopt the 15-year standard for new fossil-fueled resources acquired by the utilities. For all other contracts, including contracts for renewable generation, the utilities should be allowed recovery over the life of the contract.

Pursuant to California Public Utilities Commission ("Commission") decisions, above-market costs associated with renewable contracts are recoverable for the term of the contract. PG&E's previous response to Question 1 of MCE's second data request identified an end date of 2041 for the 2010 and 2011 vintages based on the expiration date of the last renewable contract in the portfolio. The contract was signed in 2010 and is forecast to come online later in 2016. The term of the contract is 25 years.

Similarly, the end dates for vintages 2012 through 2016 were based on the end date of the last renewable contracts in those portfolios. In this case, there are three contracts that were signed in 2012 and are forecast to come online in 2019 with an expiration date of 2043.

PG&E did qualify that the actual end date may vary and that even though the PCIA may still exist through these dates for a particular vintage, the PCIA amount in any given year could be $0 or negative up to the level of the ongoing Competition Transition Charge ("CTC") if the portfolio costs are below-market or if a positive indifference amount is offset by an accrued negative indifference amount for a particular vintage.